Raven Energy Ltd. 2004 Annual Report

Raven Energy Ltd.

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Corporate Profile

Raven Energy Ltd. is engaged in the exploration, development and production of petroleum and natural gas in Alberta. Raven's current production consists of natural gas, oil and associated liquids. We will continue to focus our exploration and development activities towards natural gas and light oil.

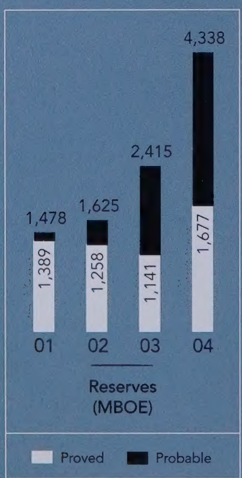
Raven's shares are listed on the TSX Venture Exchange under the trading symbol "RVL". At year end December 31, 2004 there were 33,378,552 common shares listed.

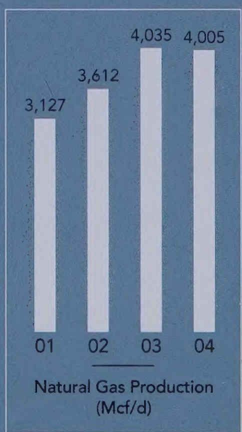
Annual General Meeting

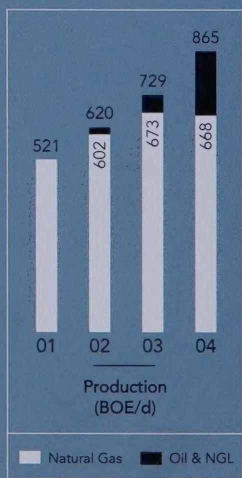
The Annual General Meeting of Raven Energy Ltd. will be held at the Westin Hotel, 320 – 4th Avenue SW at 10:00 a.m. on May 27, 2005.

Abbreviations

ARTC:	Alberta Royalty Tax Credit
bbl:	Barrel(s)
Mbbl:	Thousands of barrels
BOE:	Barrel oil equivalent (6:1)
BOE/d:	Barrel oil equivalent per day (6:1)
MBOE:	Thousands of barrels oil equivalent (6:1)
Mcf:	Thousand cubic feet
Mcf/d:	Thousand cubic feet per day
MMcf:	Million cubic feet
MMcf/d:	Million cubic feet per day
MMBtu:	Millions of British thermal units
NGL:	Natural gas liquids

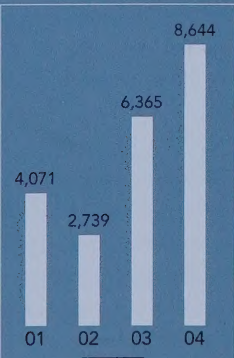




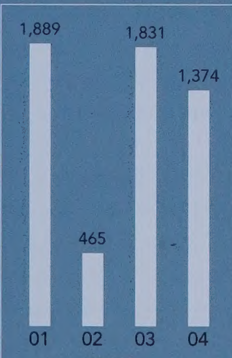


Corporate Highlights

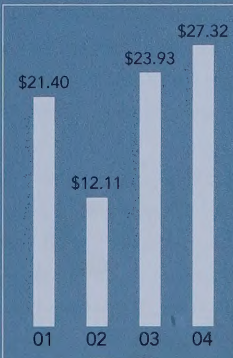
Year Ended December 31 *($ thousands, except per share amounts)*	2004	2003
		(Restated)
Petroleum and natural gas revenue	$ 13,534	$ 10,355
Net income	1,374	1,831
Per share, basic and diluted	0.05	0.08
Cash flow from operations	8,644	6,365
Per share, basic and diluted	0.28	0.29
Net capital expenditures	22,540	12,761
Shareholders' equity	31,193	19,577
Working capital (deficiency)	(2,863)	1,037
Natural gas production (Mcf/d)	4,005	4,035
Oil and NGL production (BOE/d)	197	56
Production (BOE/d)	865	729
Natural gas selling price ($/Mcf)	6.79	6.47
Oil and NGL selling price ($/bbl)	49.70	40.31
Operating expenses ($/BOE)	7.62	6.53
Cash flow netback ($/BOE)	27.32	23.93
Proved reserves (MBOE)	1,677	1,141
Proved and probable reserves (MBOE)	4,338	2,415
F and D costs ($/BOE) (proved and probable)	14.35	20.32
Undeveloped land		
Net acres (thousands)	74.1	43.5
Average working interest	90%	88%
Common shares		
Weighted average (millions)	30.4	21.9
Outstanding (millions)	33.4	27.1



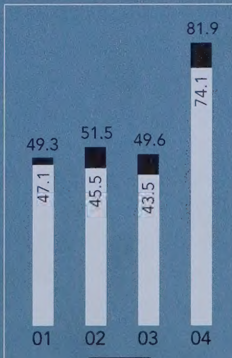
Cash Flow
($ Thousands)



Net Income
($ Thousands)



Cash Flow Netback
($/BOE)



Undeveloped Land Holdings
(Thousands of Acres)

Net Gross

Report to Shareholders

We are pleased to report on the progress of our Company during 2004.

Raven continued to focus on growth through the drilling of exploration and development projects in Alberta. In particular, the Company concentrated on the Ante Creek property located in west central Alberta. Activities at Ante Creek included the drilling of six additional oil wells and the building of production facilities. Raven is now positioned to grow production at Ante Creek with a considerable undeveloped land position, numerous development drilling locations and infrastructure to accommodate the anticipated production growth. The Company also has a drilling inventory of prospects within existing land holdings.

Raven invested $22.5 million in facilities and infrastructure, the drilling of 13 gross (10.1 net) wells and undeveloped land acquisitions. The Company participated in the construction of oil and natural gas production facilities and associated pipelines and infrastructure to allow for future growth at Ante Creek. Drilling in 2004 resulted in six net oil wells, 2.4 net natural gas wells, 0.5 net potential natural gas wells and 1.2 net dry and abandoned wells. The six oil wells (with associated natural gas) are all located on the Company's 100 percent owned Ante Creek property. Four gross (2.4 net) natural gas wells were drilled and completed in east central Alberta.

Production during 2004 increased 19 percent to 865 BOE (984 BOE in the fourth quarter of 2004) per day versus 729 BOE per day in 2003. Cash flow from operations increased to $8.6 million compared to $6.4 million in 2003. Net income was $1.4 million for 2004 compared to $1.8 million in 2003. Proved and probable reserves increased 80 percent to 4.3 million BOE at December 31, 2004 from 2.4 million BOE for 2003. The majority of the reserve additions are attributable to the Ante Creek property where the Company owns 42 sections (26,880 acres) of petroleum and natural gas leases. Undeveloped land holdings, mostly located in west central Alberta, totaled 81,900 gross (74,100 net) acres at an average 90 percent working interest. Net debt at year end was $2.9 million compared to cash flow of $8.6 million for 2004.

"Raven is now positioned to grow production at Ante Creek with a considerable undeveloped land position, numerous development drilling locations and infrastructure to accommodate the anticipated production growth."

Outlook

Activities and expenditures during 2004 have set the stage for growth in 2005. Raven has set an initial capital budget of $20 million for 2005. These expenditures will largely be financed from cash flow and lines of credit. We will continue drilling at Ante Creek where the facilities and associated infrastructure constructed in 2004 provides for ready expansion of oil and natural gas production. We will continue activities on the Viking and Inland properties, where appropriate, to maximize shallow natural gas production and associated revenue. Raven also has an inventory of other prospects on existing land holdings in west central Alberta. One of these prospects is a cased wellbore that we plan to re-enter to evaluate the natural gas potential of several zones to a depth of 5,300 meters.

During the first quarter of 2005, Raven participated in the drilling of five gross (4.4 net) wells resulting in three oil wells and two potential natural gas wells. Three net oil wells at Ante Creek were drilled, completed and equipped by late March. Raven now has 15 oil wells at Ante Creek and numerous infill locations on its existing land holdings. Two gross (1.4 net) potential natural gas wells were drilled in east central Alberta. These wells are scheduled for completion during the second quarter and will be followed up with further drilling. In 2005, Raven plans a nine well drilling program for Ante Creek. This drilling program can be expanded on the existing undeveloped land position.

Raven will continue to develop the Ante Creek property. We will also continue to target other prospects with larger reserve potential in west central Alberta that can be exploited with lower risk development drilling after initial delineation. Our goals are consistent with previous years; to achieve higher levels of production and to provide growth in shareholder value. We would like to thank our shareholders and directors for their commitment and support.

On behalf of the Board of Directors.

Laurie Smith
President & CEO
April 20, 2005

Review of Operations

Overview

Raven built a new core production area at Ante Creek in west central Alberta.

Raven participated in the drilling of 13 gross (10.1 net) wells resulting in six net oil wells, 2.4 net natural gas wells, 0.5 net potential natural gas wells and 1.2 net dry and abandoned wells. The six oil wells were all drilled at Ante Creek. Two natural gas wells (1.2 net) were drilled at Inland, one natural gas well (0.8 net) at Viking and one natural gas well (0.4 net) at Robin during 2004.

Daily production increased 19 percent during 2004 to 865 BOE from 729 BOE in 2003. Natural gas production during 2004 of 4,005 Mcf per day was comparable to 2003 production of 4,035 Mcf per day. Oil and NGL production increased to 197 barrels per day in 2004 from 56 barrels per day in 2003 as a result of additional production at Ante Creek. Cash flow netbacks increased to $27.32 per BOE from $23.93 per BOE in 2003.

Capital Expenditures ($ thousands)

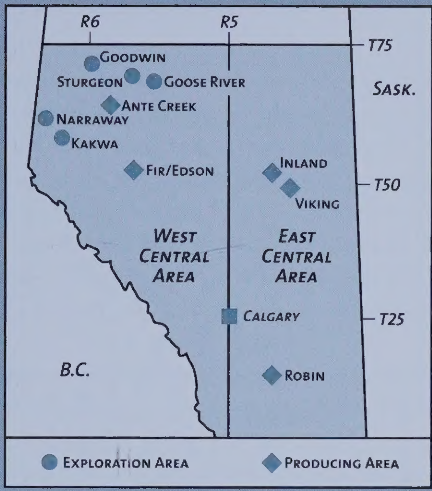
	2004	2003
Land acquisition and retention	$ 1,726	$ 1,070
Geological and geophysical	655	328
Drilling and completion	11,439	8,485
Production equipment and facilities	8,720	2,878
Total capital expenditures	$ 22,540	$ 12,761

East Central Alberta

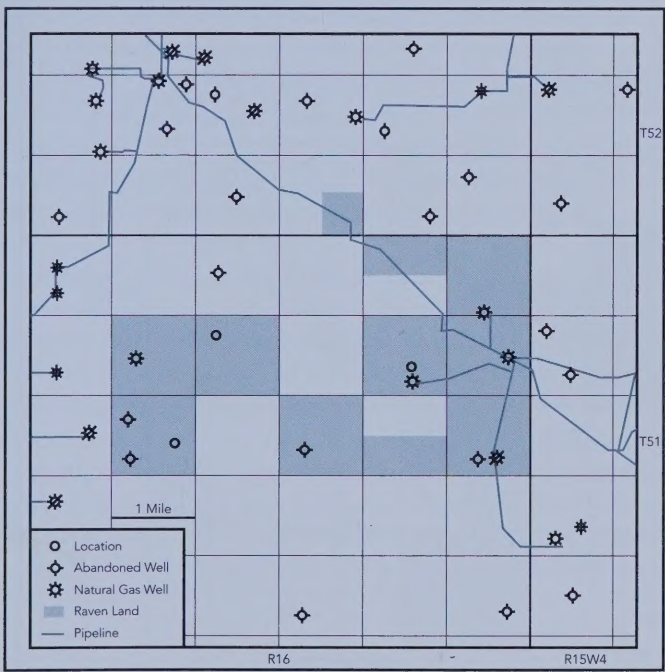
Shallow natural gas production from east central Alberta averaged 2.6 MMcf per day in 2004. The Viking property provided the majority of this production. As the exploration and development potential of the Viking property matured, the Company's focus shifted to the nearby Inland area. New production gains at Inland will help to maintain production levels in the area.

"Daily production increased 19 percent during 2004 to 865 BOE from 729 BOE in 2003."

Operating Areas



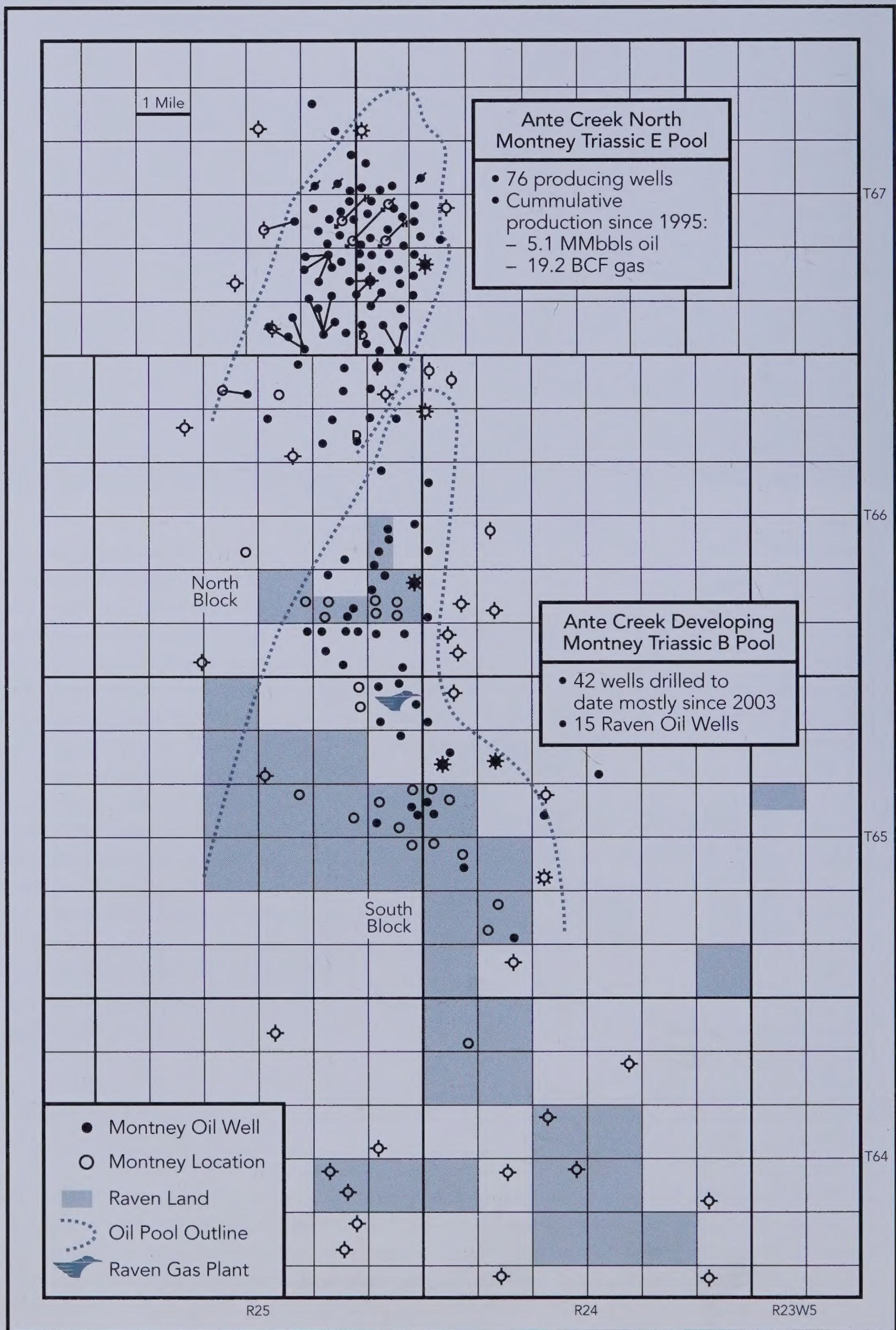
Inland



Raven drilled two natural gas wells (1.2 net) in the Inland area in 2004. One well (52.5% working interest) was placed on production in March 2004 and produced at an average rate of 550 Mcf per day for the year. The second well (70% working interest before payout, 52.5% after payout) was drilled in November and placed on production in December, 2004. This well is currently producing at a rate of 1,300 Mcf per day. A potential natural gas well was drilled late in the first quarter of 2005. This well will be completed in the second quarter of 2005. Raven has increased its land holdings in the area to 4,639 gross (2,959 net) acres. Additional seismic programs and further drilling are planned in this area for 2005.

Viking

In the Viking area, the Company drilled one development well (75% working interest) late in 2004 resulting in a producing natural gas well. Activities in this area have been reduced due to the maturity of the property. In the first quarter of 2005 the Company drilled one additional well (75% working interest) resulting in a potential natural gas well to be completed in the second quarter. Production from the Viking area totaled 1,946 Mcf per day (324 BOE) in 2004.



1 Mile
Ante Creek North
Montney Triassic E Pool
• 76 producing wells
• Cummulative production since 1995:
– 5.1 MMbbls oil
– 19.2 BCF gas
T67
T66
North Block
Ante Creek Developing
Montney Triassic B Pool
• 42 wells drilled to date mostly since 2003
• 15 Raven Oil Wells
T65
South Block
T64
Montney Oil Well
Montney Location
Raven Land
Oil Pool Outline
Raven Gas Plant
R25
R24
R23W5

WEST CENTRAL ALBERTA

Ante Creek Area

Ante Creek continued to be Raven's most active project area in 2004. Current land holdings are 42 sections (26,880 acres) which include 25,120 acres of Montney zone petroleum and natural gas rights at 100 percent working interest. Since 2003, Raven has grown this property into the Company's largest asset. Activities during 2004 included the drilling of six oil wells and the construction of oil and natural gas production facilities and associated infrastructure. Capital costs were considerable in 2004 for the Company's up front investment in a gas plant, gathering systems, batteries and sales lines. The economics for future wells significantly improve as the existing facilities are more fully utilized. Three additional oil wells were drilled in the first quarter of 2005. Raven now has 15 oil wells and numerous development locations on the existing land holdings.

The Triassic Montney zone produces light oil and associated natural gas at Ante Creek. The productive Montney zone is characterized by a thick, low permeability reservoir containing a large amount of oil and solution gas in place. There are several trends of higher porosity and permeability within the productive fairway which consists of a siltstone/sandstone reservoir over a substantial area. Production profiles for a typical well generally have higher flush production rates followed by lower more stable rates over a longer period of time.

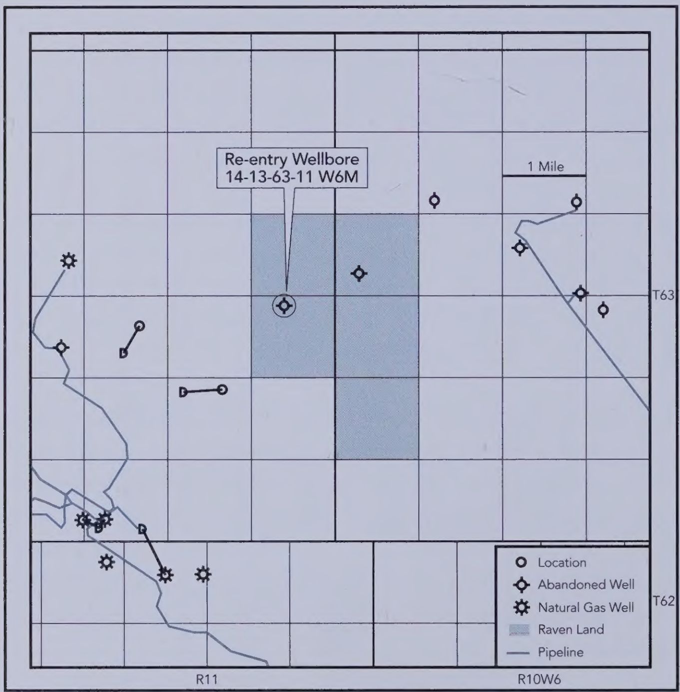
There are several significant Montney pools in the Ante Creek area which were discovered in the mid 1990's. The large reserves, located within a complex reservoir, dictate that these pools be developed with 40 to 80 acre well spacing to optimize recovery of oil and gas reserves. The Ante Creek North Triassic E Pool, developed on 80 acre spacing, located immediately north of Raven's property, is producing approximately 3,000 BOE per day. This pool has produced over 5 million barrels of oil and 19 Bcf of natural gas since production commenced in 1995. The Montney oil pools can be considered resource type plays where the large amount of oil and gas in place is attractive for future development opportunities. These opportunities include reduced drilling spacing units, horizontal wells and future improvements in technology to enhance recoveries over long periods of time.

Raven's land holdings at Ante Creek consist of the North and South blocks of lands as shown on the adjacent map. In the North block, Raven currently has eight producing Montney oil wells and an additional seven low risk, development locations based on 80 acre spacing. North Block wells produce from the upper Montney zone. In the South block the Company has six producing oil wells and one suspended well awaiting tie-in. Four of these wells produce from the upper Montney zone and two wells currently produce from a lower Montney zone discovered late in 2004. After the initial testing of the lower zone, Raven is planning to commingle both zones to optimize production and reduce operating costs. Raven has several locations on the South Block which are a combination of development drilling and step out locations of a more exploratory nature. Additional well locations on Raven's land are contingent upon delineating the best productive trends on the South Block. Raven has developed specialized completion and production techniques which include large hydraulic fracture stimulations and a gas lift system to maximize production from its wells.

Proved plus probable reserves at December 31, 2004 for Ante Creek were 11.6 Bcf of natural gas, 1,487 Mbbls of oil and 169 Mbbls of natural gas liquids. On a barrel of oil equivalent basis, the proved plus probable reserves at Ante Creek totaled 3,585 MBOE which represents 83 percent of the Company's total reserves. Production in 2004 amounted to 1,131 Mcf per day plus 188 bbls per day of oil and NGL (377 BOE per day), representing 44 percent of Raven's 2004 production.

Narraway

In the fourth quarter of 2004 Raven acquired a 100 percent working interest in five sections (3,200 acres) in the Narraway area where the Company plans to re-enter a deep well that is cased to 5,590 meters. The initial re-entry, scheduled in the second quarter, of 2005 will target the completion of a potential natural gas zone in the Mannville. Later in 2005, a deeper Devonian zone below 5,000 meters will be evaluated for its' natural gas potential.



LAND SUMMARY

Undeveloped land expenditures in 2004 were approximately $1.7 million. The Company acquired 31,840 net acres of petroleum and natural gas rights within Alberta at an average cost of $53.13 per acre. Raven continues to maintain a large undeveloped land base which is essential for the ongoing growth of an exploration company. The Company maintains high working interests in its undeveloped land holdings, all of which are within the Province of Alberta. Raven's undeveloped land position at year end was 81,900 gross (74,100 net) acres with an average working interest of 90 percent. During 2004, 24,800 gross (23,900 net) acres of undeveloped lands were added in west central Alberta. Undeveloped land holdings in west central Alberta are 65,600 gross (55,900 net) acres.

RESERVES SUMMARY

Raven had strong reserve growth in all categories during 2004. Proved plus probable reserves increased by 80 percent to 4,338 MBOE from 2,415 MBOE in 2003. Proved reserves increased to 1,677 MBOE, an increase of 47 percent from the previous year. The majority of reserve additions are from the Company's Ante Creek property where proved plus probable reserves increased to 3,585 MBOE at December 31, 2004 from 1,346 MBOE at December 31, 2003.

All reserves in this reserve section are the Company's gross reserves before royalties using forecast prices and costs.

December 31, 2004 Reserve Summary

Reserves Category	Light Oil		Natural Gas		Natural Gas Liquids	
	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)
Proved developed producing	343.7	315.6	5,757	4,353	59.4	41.6
Proved developed non-producing	103.7	94.9	839	679	8.4	5.8
Proved undeveloped	–	–	373	330	–	–
Total proved	447.4	410.5	6,969	5,362	67.8	47.4
Probable	1,036.2	957.6	9,042	6,510	118.1	81.8
Total proved plus probable	1,483.6	1,368.1	16,011	11,872	185.9	129.2

The reserve report included capital costs of $209,000 to place the proved developed non-producing reserves on production at Ante Creek. Additional capital costs of $150,000 are required to place the proved undeveloped non-producing reserves on production. Capital costs of $19.5 million are required to develop probable reserves assigned to twelve development wells at Ante Creek. These development wells are scheduled to be drilled during 2005 and 2006.

2004 Reserve Reconciliation

	Natural Gas (MMcf)		Light Oil and NGL (Mbbl)		MBOE	
	Proved	Probable	Proved	Probable	Proved	Proved and Probable
January 1, 2004	5,338	4,972	251	446	1,141	2,415
Extensions and discoveries	2,388	5,823	166	791	564	2,325
Reserve class transfers	1,392	(1,392)	199	(199)	431	–
Revisions and dispositions	(682)	(361)	(29)	116	(143)	(86)
Production	(1,466)	–	(72)	–	(316)	(316)
December 31, 2004	6,970	9,042	515	1,154	1,677	4,338

Raven's proved plus probable reserves increased from 2,415 MBOE at January 1, 2004 to 4,338 MBOE at December 31, 2004. Reserve additions of 2,325 MBOE were offset by a combined revision and disposition volume of 86 MBOE. Reserves of 431 MBOE were transferred to the proved category as a result of drilling locations that had previously been assigned probable undeveloped reserves at Ante Creek.

Present Values of Future Net Revenue Before Income Tax ($ thousands, discounted at 10%)

	2004	2003
Proved developed producing	$ 25,618	$ 10,179
Proved developed non-producing	4,775	1,116
Proved undeveloped	801	7,044
Total proved	$ 31,194	$ 18,340
Probable	18,701	11,903
Total proved plus probable	$ 49,895	$ 30,243

Summary of Pricing and Inflation Rate Assumptions as of December 31, 2004

	Oil		Natural Gas	NGL				
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40° API ($Cdn/bbl)	Natural Gas(1) AECO Gas Prices ($Cdn/MMBtu)	Edmonton Pentanes Plus ($Cdn/bbl)	Edmonton Propane ($Cdn/bbl)	Edmonton Butanes ($Cdn/bbl)	Inflation Rate(2) (%/Yr)	Exchange Rate(3) ($US/$Cdn)
2005	44.29	51.25	6.97	52.49	32.09	38.20	2.5	0.84
2006	41.60	48.03	6.66	49.19	30.07	34.01	2.5	0.84
2007	37.09	42.64	6.21	43.67	26.70	30.20	2.5	0.84
2008	33.46	38.31	5.73	39.23	23.98	27.13	2.5	0.84
2009	31.84	36.36	5.37	37.24	22.76	25.75	1.5	0.84
Thereafter								

(1) This summary table identifies benchmark reference pricing.

(2) Inflation rates for forecasting prices and costs.

(3) Exchange rates used to generate the benchmark reference prices in this table.

Finding and Development Costs, Proved and Probable

	2004	2003	2002	3 year
Capital expenditures ($ thousands)	$ 22,540	$12,761	$ 5,532	$ 40,833
Change in future capital	9,585	8,722	916	19,223
Total, including future capital	$ 32,125	$21,483	$ 6,448	$ 60,056
Reserve additions (MBOE)	2,239	1,057	373	3,669
Finding and development costs (BOE)	$ 14.35	$ 20.32	$ 17.29	$ 16.37

Finding and development costs are calculated as total capital expenditures for the applicable year plus the change in estimated future development costs divided by the reserve additions. The aggregate of the capital expenditures incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

Proved plus probable finding and development costs were $14.35 for 2004. The 2004 finding and development costs for proved reserves were $23.89 per BOE. These costs improved compared to prior years but still reflect the significant capital expenditures at Ante Creek for the gas plant and associated pipelines and facilities. The three year finding costs for proved plus probable reserves are $16.37 per BOE. Proved undeveloped reserves have been assigned only to drilled wells.

Management's Discussion & Analysis

This management's discussion and analysis (M D & A) dated April 20, 2005 should be read in conjunction with the audited financial statements for the years ended December 31, 2004 and 2003. Additional information relating to the Company, including the Company's Annual Information Form (AIF), can be found on the SEDAR website at www.sedar.com.

Certain statements throughout this M D & A, including management's assessment of the Company's future plans and operations are forward-looking statements that involve substantial known and unknown risks and uncertainties. These risk and uncertainties include, among others: risks associated with oil and gas exploration, production, marketing, and transportation such as loss of market, volatility of commodity prices, currency fluctuations, uncertainty of reserve estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources. Accordingly, events or circumstances could cause actual results to differ materially from those predicted.

The M D & A contains the terms cash flow from operations and cash flow per share. Cash flow, as used by the Company, is before changes in non-cash working capital. Cash flow and cash flow per share as presented are not defined by generally accepted accounting principles (GAAP) and therefore are referred to as non-GAAP measures. These non-GAAP measures may not be comparable to the calculation of similar measures for other entities.

In this M D & A and in the Company's 2004 annual report where amounts are expressed on a barrel of oil equivalent basis (BOE), natural gas volumes have been converted to barrels of oil at six thousand cubic feet per barrel. BOE's may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Operations Summary

	2004			2003 (restated)		
	$000's	$/BOE	%	$000's	$/BOE	%
Petroleum and natural gas revenue	$13,534	$ 42.77	100.0	$ 10,355	$ 38.93	100.0
Royalties, net of ARTC	2,110	6.67	15.6	1,874	7.05	18.1
Operating costs	2,412	7.62	17.8	1,736	6.53	16.8
Field netback	$ 9,012	$ 28.48	66.6	$ 6,745	$ 25.35	65.1
General and administrative (1)	389	1.24	2.9	299	1.12	2.9
Current taxes	–	–	–	32	0.12	0.3
Cash interest	(21)	(0.08)	(0.2)	49	0.18	0.4
Cash flow from operations	$ 8,644	$ 27.32	63.9	$ 6,365	$ 23.93	61.5
Stock based compensation	60	0.19	0.4	221	0.83	2.1
Depletion, depreciation and accretion	7,208	22.78	53.3	3,713	13.96	35.9
Future income taxes	2	0.01	–	600	2.26	5.8
Net income	$ 1,374	$ 4.34	10.2	$ 1,831	$ 6.88	17.7

(1) Net of non-cash general and administrative expenses.

Revenue and Production

Petroleum and natural gas revenue increased 31 percent to $13.5 million in 2004 due to increased production and commodity pricing. Production volume increases contributed 62 percent of the revenue growth. Average daily production volumes increased 19 percent over the prior year to average 865 BOE in 2004. Commodity price increases of 10 percent further enhanced revenue growth.

Production	2004	2003	% increase (decrease)
Natural gas (Mcf/d)	4,005	4,035	(1)
Oil and NGL (bbl/d)	197	56	252
Oil equivalent (BOE/d)	865	729	19

Average Prices	2004	2003 (restated)	% increase (decrease)
Natural gas ($/Mcf)	6.79	6.47	5
Oil and NGL ($/bbl)	49.70	40.31	23
Oil equivalent ($/BOE)	42.77	38.93	10

The Company's activities in 2004 concentrated on the development of the Ante Creek property. During the first quarter of 2004, three oil wells drilled late in 2003 were completed and placed on production. Construction of the Ante Creek plant facilities commenced in March. In the second quarter, three additional oil wells were drilled and the construction of the facilities continued despite delays related to spring breakup and adverse weather conditions. During the third quarter of 2004, start up of the natural gas plant commenced and the three oil wells drilled in the second quarter began producing. In the final quarter of 2004, Raven drilled and completed three additional wells at Ante Creek. All three wells were placed on production by year end.

The Ante Creek area contributed 44 percent of production in 2004 compared to seven percent in 2003. Increases in production realized from Ante Creek were partially offset by declines in the Viking area. Natural gas production decreased slightly to an average of 4,005 Mcf per day in 2004 (4,035 Mcf per day in 2003) although the contribution from Ante Creek increased to 28 percent from one percent in the prior year. Two new gas wells in the Inland area also contributed new natural gas production. Production of oil and natural gas liquids increased 252 percent from 56 barrels per day in 2003 to 197 barrels per day in 2004. The Ante Creek area contributed 173 barrels per day of oil and 15 barrels per day of natural gas liquids production in 2004. Production will continue to increase in 2005 with the addition of new production from both the Ante Creek and Inland areas.

	2004			2003		
Area	Natural Gas Mcf/d	Oil and NGL bbl/d	Oil Equivalent BOE/d	Natural Gas Mcf/d	Oil and NGL bbl/d	Oil Equivalent BOE/d
Ante Creek	1,131	188	377	53	45	53
Viking	1,946	–	324	3,250	–	542
Inland	355	–	59	64	–	11
Other	573	9	105	668	11	123
Total Production	4,005	197	865	4,035	56	729
% Natural Gas Production			77			92
% Oil and NGL Production			23			8

The average sales price received increased 10 percent to $42.77 per BOE in 2004 from $38.93 per BOE in 2003. Natural gas prices increased five percent to average $6.79 per Mcf in 2004 ($6.47 per Mcf in 2003) while prices received for oil and natural gas liquids increased 23 percent to average $49.70 per barrel. Due to the increased impact of production from Ante Creek, production of oil and NGL represented 23 percent of 2004 production compared to eight percent in 2003.

The Company enters into physical contracts for the sale of natural gas at fixed prices and terms to protect cash flow against price volatility. These contracts are usually for periods of less than one year and would not exceed 50 percent of Raven's anticipated production volumes. The price realized on the sale of natural gas was increased by $0.04 per Mcf in 2004 (reduced by $0.36 per Mcf in 2003) as a result of these contracts as compared to daily spot prices. Currently, the Company has contracted an average of 2.3 MMcf of natural gas per day for the period from January 1 to October 31, 2005 at an average price of approximately $7.08 per Mcf. The Company's oil and natural gas liquids are sold under 30 day evergreen contracts with prices based on marketing indices and adjusted for location, quality and transportation.

Reported prices reflect field prices, net of quality differentials, and are prior to transportation costs. In prior years transportation costs were recorded as a reduction of revenue and therefore price. In 2004 transportation costs are presented with operating costs and the 2003 prices have been recalculated to reflect this presentation. Further discussion on the presentation of transportation costs is contained in this M D & A under "Impact of new accounting policies" and in Note 2 (d) to the financial statements.

Royalties and operating expenses

	2004		2003	
Royalties	$000's	$/BOE	$000's	$/BOE
Crown royalties	$ 1,853	$ 5.85	$ 1,394	$ 5.24
Other royalties	695	2.20	829	3.12
Gross royalties	2,548	8.05	2,223	8.36
Alberta Royalty Tax Credit	(438)	(1.38)	(349)	(1.31)
Net royalties	$ 2,110	$ 6.67	$ 1,874	$ 7.05

Royalties, before ARTC, on a barrel of oil equivalent basis, decreased four percent from $8.36 to $8.05 in 2004. Crown royalties per BOE increased in 2004 due to the higher level of production from Ante Creek compared to the declining production in the Viking area. Producing wells in the Viking area are natural gas wells and receive the benefit of reduced royalty rates as productivity declines. Solution gas production from Ante Creek is subject to full Crown natural gas royalty rates. In addition, increased commodity prices resulted in higher Crown royalties in 2004.

Other royalties, consisting of freehold royalties, mineral tax and gross overriding royalties, declined on a BOE basis due to the decline in the Viking area as this production carries heavier royalty burdens than Ante Creek production. Increased Crown royalties in 2004 resulted in additional Alberta Royalty Tax Credit. The Company did not exceed the maximum allowable ARTC in 2004 but expects to exceed the allowable in 2005 which will result in an increase in net royalties paid and a decline of ARTC received on a production unit basis. On a margin basis, net royalties decreased to 15.6 percent in 2004 versus 18.1 percent in 2003. In 2005, the Company's royalty rate is expected to increase in accordance with higher prices and the dilution of the ARTC impact.

Operating expenses, which include transportation costs, increased from $6.53 per BOE in 2003 to $7.62 per BOE in 2004. Operating costs increased over the prior year due to the higher percentage of oil production which generally incurs higher operating costs than natural gas. Start up costs in the Ante Creek area also contributed to increased operating costs. Operating costs are expected to increase slightly in 2005 as Raven continues to expand production at Ante Creek.

General and administrative expenses ($ thousands)

	2004	2003 (restated)
Gross general and administrative	$ 678	$ 541
Overhead recoveries	(289)	(242)
General and administrative before stock based compensation expenses	389	299
Stock based compensation expenses	60	221
Net general and administrative expenses	$ 449	$ 520
Net general and administrative expenses per BOE	$ 1.43	$ 1.95

Gross general and administrative expenses, before overhead recoveries and stock based compensation expenses, increased approximately $140,000 due to the increased costs of annual reporting and increased staffing. On a production unit basis, gross general and administrative expenses increased to $2.15 per BOE in 2004 from $2.03 per BOE in 2003. Overhead recovered by the Company as operator of drilling and construction activities increased in 2004 in accordance with activity. General and administrative expenses, net of overhead recovered, decreased from $1.95 per

BOE in 2003 to $1.43 per BOE in 2004. Modest increases are expected in general and administrative expenses in 2005, however expenses on a production unit basis are expected to decrease with increased production.

General and administrative expenses in 2003 have been restated to reflect the adoption of the revised Canadian accounting standard for stock based compensation. Further discussion on the adoption of this policy is contained in this M D & A under "Impact of new accounting policies" and in Note 2 (b) to the financial statements.

Interest and current taxes

Interest income, net of interest expense, of approximately $21,000 was earned during 2004. Interest expense exceeded interest income by approximately $49,000 in 2003. The Company is not currently taxable on income and does not have any operations outside of Alberta. Due to the increase in the threshold for the federal Large Corporation Tax, the Company did not incur any current tax in 2004.

Cash flow from operations

Cash flow from operations increased 36 percent to $8.6 million from $6.4 million in 2003 as the result of increased production volumes and increased oil and NGL prices. On a barrel of oil equivalent basis, cash flow from operations increased 14 percent from $23.93 per BOE in 2003 to $27.32 per BOE in 2004. Cash flow per share was relatively unchanged at $0.28 per share in 2004 versus $0.29 per share in 2003. The weighted average number of shares outstanding in 2004 increased 39 percent to 30,398,224.

Depletion, depreciation and accretion

Depletion and depreciation is determined on the unit of production method based on estimated gross proved reserves at future prices and costs as determined by independent engineers. Costs of unproved properties, net of impairments, are excluded from depletion and depreciation calculations and estimated future capital costs associated with proved undeveloped reserves are included in depletion and depreciation calculations. The cost of unproved properties excluded from the depletion and depreciation calculation at December 31, 2004 were $3,064,000 ($1,793,000 in 2003) attributable to 74,100 net acres of undeveloped land at year end. Estimated future capital costs associated with proved undeveloped reserves decreased to $359,000 at December 31, 2004 from $2,532,000 at year end 2003.

Depletion, depreciation and accretion increased to $22.78 per BOE in 2004 compared to $13.96 per BOE in 2003. Depletion and depreciation increased, on a per unit basis, due to the higher finding and development costs associated with the Ante Creek property. Proved reserve estimates at Ante Creek reflect the limited production history of the wells. In addition, 2004 finding and development costs reflect considerable up front infrastructure expenditures at Ante Creek.

In 2004 the Company retroactively adopted the new Canadian accounting standard for asset retirement obligations. Further discussion on the adoption of this policy is contained in this M D & A under "Impact of new accounting policies" and in Note 2 (a) to the financial statements. The Company recognizes the fair value of an asset retirement obligation in the period in which the asset is purchased or developed. The associated asset retirement costs are capitalized with the carrying amount of the asset and are depleted and depreciated with the carrying values of the petroleum and natural gas properties. Increases in the asset retirement obligation due to the passage of time are recorded as accretion expense. The accretion of asset retirement obligations increased to $0.20 per BOE from $0.12 per BOE in 2003 as a result of increased asset retirement obligations.

The provision for asset retirement obligations are determined by management in consultation with the Company's independent engineers and are based on prevailing regulations, costs, technology and industry standards. The provision for existing asset retirement obligations was increased in 2004 to reflect increased industry costs, increases in inflation rates and changes in timing of asset retirement. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations at December 31, 2004 is $3.0 million. Current expenditures for actual abandonment and site restoration of producing properties were nil.

Future income taxes

The future income tax provision for 2004 decreased to approximately $2,000 ($600,000 in 2003) due to the decrease in pretax income and recoveries resulting from decreases in corporate income tax rates. Income before income taxes decreased approximately $1.1 million as increases in depletion, depreciation and accretion more than offset cash flow increases realized from increased production and commodity pricing. The Company's future income tax provision for 2004 includes a reduction of approximately $449,000 ($280,000 in 2003) due to changes in the Federal and Alberta corporate income tax rates. The Company has approximately $25.0 million of tax pools remaining at December 31, 2004 and, depending on commodity prices and the amount and tax classification of expenditures, may be taxable on a current basis in 2005.

Net income

Net income decreased to $1.4 million versus $1.8 million in 2003 as a result of increased depletion partially offset by increased production volumes and commodity prices and reduced future income tax provisions. Net income per share decreased to $0.05 per share versus $0.08 per share in 2003.

IMPACT OF NEW ACCOUNTING POLICIES

Oil and gas accounting

Effective January 1, 2004, the Company adopted the new Canadian accounting guideline for the full cost method of accounting for oil and gas activities. The new guideline requires a detailed impairment calculation, at least annually, to determine that the carrying value of petroleum and natural gas assets does not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceeds the carrying value of the petroleum and natural gas assets. When the carrying value is assessed not to be recoverable, an impairment loss is recognized to the extent that the carrying value of the petroleum and natural gas assets exceeds the sum of the discounted cash flows from proved and probable reserves plus the lower of cost and market of unproved properties. The cash flows are estimated using expected future product prices and costs and discounted using a risk-free interest rate. Adoption of the new guideline had no effect on the Company's financial statements.

Asset retirement obligations

Effective January 1, 2004, the Company retroactively adopted the new Canadian accounting standard for asset retirement obligations with restatement of prior periods. The Company records the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the asset, normally when the asset is purchased or developed. The associated asset retirement costs are capitalized as part of the carrying amount of the asset and depleted and depreciated using a unit of production method over estimated gross proved reserves. Subsequent to the initial measurement of the asset retirement obligations, the obligations are adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation. The impact of adoption of this policy is disclosed in Note 2 (a) to the financial statements.

Stock based compensation and other stock-based payments

Effective January 1, 2004, the Company retroactively adopted the revised Canadian accounting standard for stock based compensation and other stock based payments with restatement of prior periods. Prior to January 1, 2004, no compensation cost was recorded for stock options granted to employees and directors. The Company previously disclosed the pro forma effect of accounting for these awards under the fair value based method. The impact of adoption of this policy is disclosed in Note 2 (b) to the financial statements.

Transportation costs

Effective January 1, 2004, transportation costs are presented with operating expenses in the Statements of Income and Retained Earnings. In 2003, transportation costs were recorded as a reduction of revenue and have been reclassified to conform to the presentation adopted in 2004.

Liquidity and capital resources

Capital expenditures of $22.5 million were financed through a combination of cash flow, the proceeds of private placements completed during the year and the utilization of working capital. In March, 2004 the Company issued 4,000,000 common shares through a private placement for gross proceeds of $7.0 million. In December, 2004, the Company completed a private placement of 2,000,000 flow-through common shares for gross proceeds of $3.4 million. The total outstanding common shares were 33,378,552 at December 31, 2004.

At December 31, 2004 the Company had a working capital deficiency of approximately $2.9 million and unutilized bank facilities of $5 million. Subsequent to year end, in February 2005, the banking facilities were increased to $8.0 million. Banking facilities available to the Company are in part determined by the borrowing base of the Company. This borrowing base may be reduced by several factors including a material decline in commodity prices or revisions in reserve estimates, thereby reducing the bank credit available to the Company.

The 2005 capital budget has been approved at $20 million and will be funded through cash flow and utilization of credit facilities. Raven's cash flow and earnings are highly sensitive to changes in commodity prices, exchange rates and other factors that are beyond the control of the Company. Therefore, the Board of Directors reviews the capital budget throughout the year and adjusts it according to current industry conditions including financing capabilities at that time.

Business risks

Exploration, development and production of petroleum and natural gas involve many risks that even the combination of experience and careful evaluation may not be sufficient to overcome. Utilizing highly skilled professionals, focusing in areas where the Company has existing knowledge and expertise or access to such expertise, using up to date technology, and controlling costs to maximize margins, mitigate these risks. The Company maintains a comprehensive insurance program that insures liability and property consistent with industry practice. The program is designed to mitigate risks and protect against significant loss. However, the Company is not fully insured against all these risks, nor are all such risks insurable.

The reserve and recovery information contained in Raven's independent reserve evaluation is only an estimate. The actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by the independent reserve evaluator. A significant portion of Raven's assets is the Ante Creek property whose relatively short production history may make estimates on this property more subject to revisions. The reserve report was prepared using certain commodity price assumptions that are described in the reserve section of this report. If lower prices for crude oil, natural gas liquids and natural gas are realized by Raven and substituted for the price assumptions used in the reserve report, the present value of estimated future net cash flows for the reserves would be reduced and the reduction could be significant.

Financial risks include exposure to fluctuation in commodity prices, currency exchange rates, and interest rates. To mitigate commodity risk, the Company maintains direct marketing control over its production. The Company enters into physical contracts for the sale of natural gas at fixed prices and terms and currently has fixed pricing arrangements as disclosed earlier. Although not currently utilized, the Company may institute financial hedging techniques for interest rates, currency exchange rates and commodity prices. If utilized, such transactions would be subject to certain limits on term and amount as established by the Board of Directors.

Summary of Quarterly Results

($ thousands, except per share) (unaudited)

2004 Quarter Ended	March 31	June 30	September 30	December 31
Revenue before royalties	$ 2,680	$ 3,127	$ 3,695	$ 4,032
Cash flow from operations	1,614	2,107	2,444	2,479
$ Per basic share	0.06	0.07	0.08	0.08
$ Per diluted share	0.06	0.07	0.08	0.08
Net income	236	312	266	559
$ Per basic share	0.01	0.01	0.01	0.02
$ Per diluted share	0.01	0.01	0.01	0.02
Capital expenditures	5,809	6,581	2,943	7,207
Production (BOE/d)	712	796	963	984

2003 Quarter Ended (restated)	March 31	June 30	September 30	December 31
Revenue before royalties	$ 3,147	$ 2,295	$ 2,717	$ 2,196
Cash flow from operations	1,945	1,328	1,702	1,391
$ Per basic share	0.09	0.06	0.08	0.06
$ Per diluted share	0.09	0.06	0.08	0.06
Net income (loss)	540	775	667	(151)
$ Per basic share	0.02	0.04	0.03	(0.01)
$ Per diluted share	0.02	0.04	0.03	(0.01)
Capital expenditures	2,753	2,706	1,850	5,451
Production (BOE/d)	782	681	793	660

Quarterly revenues and cash flows in 2004, as compared to the same periods in 2003, increased to reflect higher production volumes and commodity pricing. Capital expenditures have increased over 2003 due to development of the Ante Creek property. Third quarter expenditures in both years decreased compared to other quarters due to the seasonality of field operations. Net income decreased in the final quarter of 2003 due to increases in non-cash provisions for depletion and future income taxes as a result of reserve revisions.

Selected Annual Information ($ thousands, except per share)

	2004	2003 (restated)	2002 (restated)
Revenue before royalties	$ 13,534	$ 10,355	$ 5,083
Cash flow from operations	8,644	6,365	2,739
$ Per basic share	0.28	0.29	0.14
$ Per diluted share	0.28	0.29	0.14
Net income	1,374	1,831	465
$ Per basic share	0.05	0.08	0.02
$ Per diluted share	0.05	0.08	0.02
Capital expenditures	22,540	12,761	5,532
Total assets	42,866	30,691	15,477
Working capital (deficiency)	(2,863)	1,037	(781)
Long term financial liabilities			
Future abandonment obligations	1,773	548	365
Future income taxes	$ 4,195	$ 4,381	$ 3,459
Production (BOE/d)	865	729	620

Net Asset Value ($ thousands, except per share)

	2004	2003
Present value of appraised reserves (1)	$ 49,895	$ 30,243
Appraised value of undeveloped land (2)	5,354	2,467
Working capital (deficiency)	(2,863)	1,037
Net asset value (3)	$ 52,386	$ 33,747
Net asset value per share (4)	$ 1.57	$ 1.24

(1) Proved plus probable reserves discounted at 10 percent before income taxes.

(2) Based on independent appraisals at December 31, 2004 and 2003.

(3) Excludes the value of proprietary seismic and other assets.

(4) 33,378,552 shares outstanding at December 31, 2004 (27,128,552 in 2003).

Outstanding Share Data

There have been no issues of common shares or grants of stock options subsequent to year end. As at April 20, 2005 there are 33,378,552 common shares outstanding and 750,000 stock options outstanding.

Management's Report

The accompanying financial statements and all information in the Annual Report are the responsibility of management. The financial statements have been prepared by management in accordance with the accounting policies in the notes to the financial statements. When necessary, management has made informed judgments and estimates in accounting for transactions which were not complete at the balance sheet date. In the opinion of management, the financial statements have been prepared within acceptable limits of materiality, and are in accordance with Canadian generally accepted accounting principles (GAAP) appropriate in the circumstances. The financial information elsewhere in the Annual Report has been reviewed to ensure consistency with that in the financial statements.

Management has prepared Management's Discussion and Analysis (MD&A). The MD&A is based upon the Company's financial results prepared in accordance with Canadian GAAP. The MD&A compares the audited financial results for the twelve months ended December 31, 2004 to December 31, 2003.

Management maintains appropriate systems of internal control. Policies and procedures are designed to give reasonable assurance that transactions are properly authorized, assets are safeguarded and financial records properly maintained to provide reliable information for the preparation of financial statements.

KPMG LLP, an independent firm of Chartered Accountants, was engaged, as approved by a vote of shareholders at the Company's most recent annual general meeting, to audit the financial statements in accordance with generally accepted auditing standards in Canada and provide an independent professional opinion.

The Audit Committee of the Board of Directors has discussed the financial statements, including the notes thereto, with management and external auditors. The financial statements have been approved by the Board of Directors on the recommendation of the Audit Committee.

Laurie Smith
President & CEO
April 11, 2005

Sharon Supple

Sharon Supple
Chief Financial Officer

Auditors' Report to the Shareholders

We have audited the balance sheets of Raven Energy Ltd. as at December 31, 2004 and 2003 and the statements of income and retained earnings and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2004 and 2003 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants
Calgary, Canada
April 11, 2005

Balance Sheets

December 31	2004	2003
		[restated]
Assets		[note 2]
Current assets		
Cash and cash equivalents	$ 621,293	$ 4,619,820
Accounts receivable	2,106,947	2,521,631
Prepaid expenses and deposits	113,411	81,776
	2,841,651	7,223,227
Petroleum and natural gas properties *[note 3]*	40,024,437	23,467,886
	$ 42,866,088	$ 30,691,113
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities	$ 5,705,124	$ 6,185,865
Asset retirement obligations *[note 5]*	1,772,800	548,000
Future income taxes *[note 6]*	4,194,700	4,380,500
Shareholders' equity		
Share capital *[note 7]*	24,546,378	14,344,332
Contributed surplus *[note 7]*	264,937	224,482
Retained earnings	6,382,149	5,007,934
	31,193,464	19,576,748
	$ 42,866,088	$ 30,691,113

See accompanying notes to financial statements.

Approved on behalf of the Board

David H. Erickson
Director

John D.G. van der Lee
Director

Statements of Income & Retained Earnings

Years ended December 31	2004	2003
		[restated] [note 2]
Revenue		
Petroleum and natural gas	$ 13,534,369	$ 10,355,140
Royalties, net of Alberta Royalty Tax Credit	(2,109,686)	(1,874,373)
	11,424,683	8,480,767
Expenses		
Operating	2,412,481	1,736,607
General and administrative	449,114	519,622
Interest	(21,342)	48,746
Depletion, depreciation and accretion	7,207,900	3,713,150
	10,048,153	6,018,125
Income before income taxes	1,376,530	2,462,642
Income taxes *[note 6]*		
Current	–	31,797
Future	2,315	600,145
	2,315	631,942
Net income	1,374,215	1,830,700
Retained earnings, beginning of year		
As previously reported	5,186,792	3,177,234
Changes in accounting policies *[note 2]*	(178,858)	–
As restated	5,007,934	3,177,234
Retained earnings, end of year	$ 6,382,149	$ 5,007,934
Earnings per share – basic and diluted	$ 0.05	$ 0.08
Weighted average number of common shares outstanding – basic	30,398,224	21,929,649
Weighted average number of common shares outstanding – diluted	30,693,350	22,289,342

See accompanying notes to financial statements.

Statements of Cash Flows

Years ended December 31	2004	2003
		[restated]
Cash provided by (used in):		[note 2]
Operating activities		
Net income	$ 1,374,215	$ 1,830,700
Items not involving cash:		
Stock based compensation *[note 7(d)]*	59,721	221,271
Depletion, depreciation and accretion	7,207,900	3,713,150
Future income taxes	2,315	600,145
Funds from operations	8,644,151	6,365,266
Change in non-cash working capital	(350,613)	(90,704)
	8,293,538	6,274,562
Financing activities		
Issue of share capital, net of issuance costs	9,994,665	8,213,244
Change in non-cash working capital	10,935	1,217
	10,005,600	8,214,461
Investing activities		
Petroleum and natural gas properties	(22,539,651)	(12,760,580)
Change in non-cash working capital	241,986	2,827,531
	(22,297,665)	(9,933,049)
Increase (decrease) in cash and cash equivalents	(3,998,527)	4,555,974
Cash and cash equivalents, beginning of year	4,619,820	63,846
Cash and cash equivalents, end of year	$ 621,293	$ 4,619,820

See accompanying notes to financial statements.

	2004	2003
Supplemental cash flow information:		
Cash received (paid) during the year for:		
Interest expense	$ 17,725	$ (58,114)
Income taxes	$ –	$ (31,797)

Notes to the Financial Statements

Years ended December 31, 2004 and 2003

Raven Energy Ltd. (the "Company") is incorporated under the Business Corporations Act (Alberta). The principal business activities of the Company are the exploration, development and production of petroleum and natural gas in Alberta.

1. SIGNIFICANT ACCOUNTING POLICIES:

(a) Basis of presentation

The financial statements of the Company have been prepared by management in accordance with Canadian generally accepted accounting principles. The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that effect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the period. Actual results could differ from those estimates.

(b) Petroleum and natural gas properties:

(i) Petroleum and natural gas properties

The Company follows the full cost method of accounting for petroleum and natural gas operations whereby all costs related to the acquisition, exploration and development of petroleum and natural gas reserves are capitalized. Such costs include lease acquisition costs, geological and geophysical costs, carrying charges of non-producing properties, costs of drilling both productive and non-productive wells, the cost of petroleum and natural gas production equipment and overhead charges directly related to exploration and development activities.

Capitalized costs, together with estimated future capital costs associated with proved reserves, are depleted and depreciated using the unit of production method based on estimated gross proved reserves at future prices and costs as determined by independent engineers. Petroleum and natural gas reserves and production are converted into equivalent units based on relative energy content of six thousand cubic feet of natural gas to one barrel of petroleum. Costs of unproved properties, net of impairments, are excluded from the depletion and depreciation calculation. These properties are assessed periodically to ascertain whether impairment has occurred. When proved reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of impairment is added to costs subject to depletion.

The capitalized costs, less accumulated depletion and depreciation, are evaluated at year end to determine that the costs are recoverable and do not exceed the fair value of the properties. The costs are assessed to be recoverable if the sum of the undiscounted cash flows expected from the production of proved reserves and the lower of cost and market of unproved properties exceeds the carrying value of the petroleum and natural gas assets. When the carrying value is assessed not to be recoverable, an impairment loss is recognized to the extent that the carrying value of the petroleum and natural gas assets exceeds the sum of the discounted cash flows from proved and probable reserves plus the lower of cost and market of unproved properties. The cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

Proceeds from the sales of petroleum and natural gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would significantly alter the rate of depletion and depreciation.

(ii) Asset retirement obligations

The Company records the fair value of an asset retirement obligation as a liability in the period in which it incurs a legal obligation associated with the asset, normally when the asset is purchased or developed. The associated asset retirement costs are capitalized as part of the carrying amount of the long lived asset and depleted and depreciated using a unit of production method over estimated gross proved reserves. Subsequent to the initial measurement of the asset retirement obligations, the obligations are adjusted at the end of each period to reflect the passage of time and changes in the estimated future cash flows underlying the obligation.

(iii) Joint activities

The Company conducts some exploration and production activities jointly with others and accordingly these statements reflect only the Company's proportionate interest in such activities.

(c) Income taxes:

The Company follows the liability method of accounting for future income taxes. Under the liability method, future income tax assets and liabilities are determined based on "temporary differences" (differences between the accounting basis and the tax basis of the assets and liabilities), and are measured using the currently enacted, or substantively enacted, tax rates and laws expected to apply when these differences reverse. Income tax expense is the sum of the Company's provision for current income taxes and the difference between opening and ending balances of the future income tax assets and liabilities.

(d) Flow-through shares:

The Company has financed a portion of its petroleum and natural gas exploration activities with flow-through share issues. The exploration and development expenditures funded by flow-through share expenditures are renounced to investors in accordance with tax legislation. The estimated value of the tax pools foregone is reflected as a reduction in share capital with a corresponding increase in future income tax liability when the expenditures are renounced.

(e) Stock based compensation:

The Company has an equity incentive plan, which is described in note 7 (d).

The Company accounts for its stock based compensation plan for directors, officers and employees using the fair value method. Under the fair value method, compensation cost attributable to all stock options granted to employees and directors is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. Upon the exercise of the option, consideration received together with the amount previously recognized in contributed surplus is recorded as an increase to share capital.

(f) Per share amounts:

Basic per share amounts are calculated using the weighted average number of common shares outstanding during the year. Diluted per share amounts are calculated based on the treasury stock method, which assumes that any proceeds obtained on the exercise of options plus the unamortized stock based compensation expense would be used to purchase common shares at the average market price during the period. The weighted average number of shares outstanding is then adjusted by the net change.

(g) Measurement uncertainty:

The amounts recorded for depletion and depreciation of petroleum and natural gas properties and the provision for asset retirement obligations are based on estimates. The cost recovery test is based on estimates

of proved reserves, production rates, commodity prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the financial statements of changes in such estimates in future periods could be significant.

(h) Financial instruments:

The Company periodically uses certain financial instruments to hedge its exposure to commodity price fluctuation on a portion of its petroleum and natural gas sales. Gains and losses on these transactions are reported as adjustments to revenue when the related production is sold.

(i) Foreign currency translation:

Monetary items denominated in foreign currency are translated to Canadian dollars at the rate in effect at the balance sheet date and non-monetary items are translated at rates of exchange in effect when the assets were acquired or obligations incurred. Revenue and expenses are translated at rates in effect at the time of the transactions. Foreign exchange gains and losses are included in income.

(j) Cash and cash equivalents:

Cash and cash equivalents consist of cash in the bank, less outstanding cheques, and short term deposits with a maturity of three months or less.

(k) Revenue recognition:

Revenues from the sale of petroleum and natural gas are recorded when title passes to an external party.

2. CHANGES IN ACCOUNTING POLICIES:

(a) Asset retirement obligations:

Effective January 1, 2004, the Company retroactively adopted the new Canadian accounting standard for asset retirement obligations with restatement of prior periods. Previously, estimated future site restoration and abandonment costs were depleted over the life of the proved reserves and actual costs were charged to the accumulated provision account as incurred. The effect of adoption of the new standard on the financial statements is presented below as increases (decreases):

Balance sheet as at December 31, 2003	
Asset retirement costs, included in petroleum and natural gas properties	$ 332,025
Asset retirement obligations	548,000
Future income tax liability	28,500
Accumulated future abandonment and site restoration	(258,300)
Retained earnings	13,825

Statement of Income and Retained Earnings for the year ended December 31, 2003	
Accretion expense, included in depletion, depreciation and accretion	$ 32,000
Depletion and depreciation on asset retirement costs	77,270
Amortization of estimated future abandonment and site restoration liability	(112,200)
Future income tax expense	(10,895)
Net income	13,825

Earnings per share, both basic and diluted, were unchanged as a result of this restatement.

(b) Stock based compensation:

Effective January 1, 2004, the Company retroactively adopted the revised Canadian accounting standard for stock based compensation and other stock based payments with restatement of prior periods. Prior to January 1, 2004, no compensation cost was recorded for stock options granted to employees and directors. The Company previously disclosed the pro forma effect of accounting for these awards under the fair value based method.

For the year ended December 31, 2003, the net effect on the financial statements of using the fair value method of accounting for stock based compensation was an increase in stock compensation expense and a decrease in net income of $192,683. Contributed surplus at December 31, 2003 increased by $192,683 with an offsetting decrease to retained earnings. Earning per share, both basic and diluted, decreased by $0.01 for the year ended December 31, 2003. The restatement had no effect on 2002 as no options were granted to employees or directors in that year.

(c) Full cost ceiling test:

Effective January 1, 2004, the Company adopted the new Canadian accounting guideline for the full cost method of accounting for oil and gas activities. The new guideline requires a detailed impairment calculation, at least annually, to determine that the carrying value of petroleum and natural gas assets does not exceed the fair value of the properties.

Prior to January 1, 2004, an impairment loss was recognized when the carrying amount of the petroleum and natural gas assets exceeded its recoverable amount. The recoverable amount was equal to the estimated future net revenue from proved reserves (based on prices and costs at the balance sheet date) plus the unimpaired costs of unproved properties less estimated future administrative expenses, development costs, financing costs and income taxes.

Adoption of the new guideline had no effect on the Company's financial statements.

(d) Transportation costs:

Effective January 1, 2004, transportation costs are presented with operating expenses in the Statements of Income and Retained Earnings. In 2003, transportation costs were recorded as a reduction of revenue and have been reclassified to conform to the presentation adopted in 2004.

3. PETROLEUM AND NATURAL GAS PROPERTIES:

	2004	2003 [restated] [note 2]
Petroleum and natural gas properties	$ 54,740,696	$ 31,039,045
Accumulated depletion and depreciation	14,716,259	7,571,159
	$ 40,024,437	$ 23,467,886

Costs of unproved properties excluded from costs subject to depletion and depreciation at December 31, 2004 were approximately $3,064,000 ($1,793,000 - 2003). Future development costs of proven undeveloped reserves of $359,000 ($2,532,000 - 2003) were included in costs subject to depletion and depreciation.

The benchmark and Company prices on which the December 31, 2004 ceiling test for impairment is based, are as follows:

	Oil		Natural gas	
Year	Edmonton par 40° API ($/bbl)	Company ($/bbl)	AECO Gas prices ($/MMBtu)	Company ($/Mcf)
2005	51.25	49.05	6.97	7.12
2006	48.03	45.83	6.66	6.83
2007	42.64	40.44	6.21	6.39
2008	38.31	36.11	5.73	5.91
2009	36.36	34.16	5.37	5.54

Oil and natural gas prices increase at a rate of approximately two per cent per year after 2009 until the end of the reserves life.

4. BANK FACILITY:

The Company currently has access to a demand revolving facility of $5,000,000 from a Canadian chartered bank. The credit facility bears interest at the bank's prime rate plus 0.50% per annum and is secured by a general security agreement constituting a first ranking security interest in all personal property and a first ranking charge on all real property. As at December 31, 2004 and 2003 the line of credit was unutilized.

5. ASSET RETIREMENT OBLIGATIONS:

The Company's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Company estimates the total undiscounted amount of cash flows required to settle its asset retirement obligations is approximately $3,000,000 which will be incurred between 2005 and 2018. The majority of the costs will be incurred between 2005 and 2015. A credit adjusted risk-free interest rate of 8.5 percent and inflation rates of 1.5 to 2.5 percent were used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

	2004	2003 [restated] [note 2]
Balance, beginning of year	$ 548,000	$ 365,000
Accretion expense	$ 62,800	$ 32,000
Liabilities incurred	$ 555,100	$ 151,000
Revision of liabilities	$ 606,900	$ -
Balance, end of year	$ 1,772,800	$ 548,000

6. INCOME TAXES:

(a) The provision for income taxes differs from the amounts which would be obtained by applying the combined federal and provincial income tax rate as follows:

	2004	2003
		[restated]
		[note 2]
Income tax rate	38.62%	40.62%
Expected income tax provision	$ 531,616	$1,000,325
Increase (decrease) in taxes resulting from:		
Non-deductible crown payments	566,398	552,803
Resource allowance	(524,976)	(631,025)
Alberta Royalty Tax Credit	(147,873)	(134,507)
Future income tax rate reduction	(449,220)	(279,546)
Stock based compensation	23,064	89,880
Large corporation tax	–	31,797
Other	3,306	2,215
	$ 2,315	$ 631,942

(b) The components of the Company's net future income tax liability at December 31, 2004 and 2003 are as follows:

	2004	2003
		[restated]
		[note 2]
Petroleum and natural gas properties	$(5,044,798)	$ (4,718,249)
Asset retirement obligations	588,942	183,896
Share issue costs	261,156	153,853
	$(4,194,700)	$ (4,380,500)

7. SHARE CAPITAL:

(a) Authorized:

The authorized share capital consists of an unlimited number of common shares without nominal or par value and an unlimited number of preferred shares, issuable in series. No preferred shares have been issued.

(b) Common shares issued:

	2004		2003	
	Number of Shares	Amount	Number of Shares	Amount
Balance, beginning of year	27,128,552	$ 14,344,332	21,028,552	$ 6,452,738
Issued on exercise of stock options	250,000	143,266	350,000	35,000
Private placements for cash	6,000,000	10,400,000	5,750,000	8,600,000
Income tax effect of flow-through shares		–		(478,390)
Share issue costs		(529,335)		(421,756)
Income tax effect of share issue costs		188,115		156,740
Balance, end of year	33,378,552	$ 24,546,378	27,128,552	$ 14,344,332

(c) Private placements:

On December 15, 2004 the Company completed a private placement of 2,000,000 flow-through common shares at a price of $1.70 per share for gross proceeds of $3,400,000. Directors and officers of the Company subscribed for 253,000 flow-through common shares for consideration of $430,100. Total flow-through share issues during the year were $3,400,000 of which $3,050,000 remains to be expended on qualifying expenditures by December 31, 2005.

On March 24, 2004 the Company completed a private placement of 4,000,000 common shares at a price of $1.75 per share for gross proceeds of $7,000,000.

On December 18, 2003 the Company completed a private placement of 3,750,000 common shares at a price of $1.60 per share for gross proceeds of $6,000,000.

On September 22, 2003 the Company completed a private placement of 1,000,000 units at a price of $2.60 per unit for gross proceeds of $2,600,000. Each unit consisted of one common share and one flow-through common share. Directors and officers of the Company subscribed for 94,000 units for consideration of $244,400.

(d) Stock option plan:

The Company has a stock option plan authorizing the grant of options to acquire shares to designated participants (being directors, officers, employees or consultants). At December 31, 2004 options reserved for issuance under the plan are 2,500,000 of which 750,000 are outstanding and 1,750,000 remain available for future grants. The aggregate number of options that may be granted to any one individual must not exceed five percent of the total issued and outstanding shares. Options are granted at exercise prices equal to the market value of the shares at the date of grant and are granted for a five year term. Options granted to officers and directors vest immediately. The vesting periods for options granted to employees and consultants are determined by the Board at the time of the specific grant.

The following table summarizes the changes in the Company's stock option plan:

	2004		2003	
	Number options	Weighted average exercise price	Number of options	Weighted average exercise price
Balance, beginning of year	900,000	$ 0.95	800,000	$ 0.55
Granted	100,000	$ 1.80	450,000	$ 1.00
Exercised	(250,000)	$ 0.50	(350,000)	$ 0.10
Balance, end of year	750,000	$ 1.21	900,000	$ 0.95
Options exercisable at end of year	683,334	$ 1.16	850,001	$ 0.95

The following table summarizes information about the stock options outstanding at December 31, 2004:

Options outstanding				Options exercisable	
Range of exercise prices	Number outstanding	Weighted average remaining contractual life (years)	Weighted average exercise price	Number exercisable	Weighted average exercise price
$1.00-1.39	450,000	3.0	$1.00	450,000	$1.00
$1.40-1.79	200,000	1.5	$1.40	200,000	$1.40
$1.80-2.00	100,000	4.2	$1.80	33,334	$1.80
$1.00-2.00	750,000	2.8	$1.21	683,334	$1.16

The fair value of options granted are estimated on the date of the grant using the Black-Scholes option pricing model with the following weighted average assumptions: zero dividend yield, expected volatility of fifty percent, risk-free interest rates of four percent and expected life of five years. The weighted average fair market value of options granted during 2004 was $0.87 per option ($0.48 per option - 2003).

(e) Contributed surplus:

A reconciliation of contributed surplus is provided below:

	2004	2003 [restated] [note 2]
Balance, beginning of year	$ 224,482	$ 3,211
Stock based compensation expense	$ 59,721	$ 221,271
Transfer to share capital on exercise of options	$ (19,266)	$ -
Balance, end of year	$ 264,937	$ 224,482

8. RISK MANAGEMENT:

(a) Interest rate risk:

The Company is exposed to interest rate fluctuations on any outstanding bank indebtedness.

(b) Credit risk:

A substantial portion of the Company's accounts receivable are with customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Purchasers of the Company's petroleum and natural gas are subject to an internal credit review to minimize the risk of non-payment.

(c) Commodity risk:

The Company has a price risk management program whereby the commodity price associated with a portion of its future production is fixed. The Company has entered into fixed priced sales contracts for a portion of its future natural gas production resulting in an average contracted volume of 2.3 million cubic feet per day for the period January 1, 2005 to October 31, 2005 at a weighted average contract price of $7.08 per thousand cubic feet.

(d) Fair value of financial instruments:

Financial instruments of the Company consist of cash and cash equivalents, accounts receivable, prepaid expenses and deposits, accounts payable and accrued liabilities. At December 31, 2004 there are no significant differences between the carrying value of such instruments reported on the balance sheet and their estimated market value due to their short term to maturity.

Corporte Information

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Laurie J. Smith*
John D.G. van der Lee*

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Auditors
KPMG LLP
Calgary, Alberta

Listed
TSX Venture Exchange
Common Share Symbol: RVL

Web Site
www.ravenenergy.com

Certain statements throughout this annual report, including management's assessment of the Company's future plans and operations are forward-looking statements that involve substantial known and unknown risks and uncertainties. These risk and uncertainties include, among others: risks associated with oil and gas exploration, production, marketing, and transportation such as loss of market, volatility of commodity prices, currency fluctuations, uncertainty of reserve estimates, environmental risks, competition from other producers and ability to access sufficient capital from internal and external sources. Accordingly, events or circumstances could cause actual results to differ materially from those predicted.

raven energy ltd.

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